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BEFORE THE ARIZONA CORPORATION COMMISSION

TOM FORESE, CHAIRMAN
BOB BURNS, COMMISSIONER
DOUG LITTLE, COMMISSIONER
ANDY TOBIN, COMMISSIONER
BOYD DUNN, COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	**DOCKET NO. E-01345A-16-0036** **DOCKET NO. E-01345A-16-0123**
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	**ENERGY FREEDOM COALITION OF AMERICA'S NOTICE OF FILING REPLY TESTIMONY OF MARK E. GARRETT**

Energy Freedom Coalition of America ("EFCA") hereby provides notice of filing the reply testimony of Mark E. Garrett in the above referenced matter.

Respectfully submitted this 18th day of April, 2017.

/s/ Court S. Rich
Court S. Rich
Attorney for Energy Freedom Coalition of America

Original and 13 copies filed on this 18th day of April, 2017 with:

Docket Control
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I hereby certify that I have this day served a copy of the foregoing document on all parties of record in this proceeding by regular or electronic mail to:

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-16-0036 DOCKET NO. E-01345A-16-0123
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	

DIRECT TESTIMONY

OF

MARK E. GARRETT

RATE DESIGN ISSUES

ON BEHALF OF

ENERGY FREEDOM COALITION OF AMERICA ("EFCA")

April 17, 2017

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 50 Penn Place, 1900 N.W. Expressway, Suite 410, Oklahoma City, Oklahoma 73118.

Q: DID YOU PROVIDE TESTIMONY ON DECEMBER 21, 2016 IN THE REVENUE REQUIREMENT PHASE OF THESE PROCEEDINGS AND ON APRIL 3, 2017 IN THE RATE DESIGN PHASE?

A: Yes. A description of my qualifications and a list of the proceedings in which I have been involved were attached to my December 21, 2016 testimony.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of Energy Freedom Coalition of America ("EFCA").

Q: WHAT IS THE PURPOSE OF YOUR RATE DESIGN TESTIMONY?

A: Pursuant to Section 20.5 of the Settlement Agreement reached in this case, the parties agreed that alternative rate design for large commercial and industrial customers would remain unsettled and that they would ask the Commission to decide this issue independent of the Settlement Agreement. As a result, my direct rate design testimony was offered to address alternative rate designs for Schedule E-32 L and E-32 L TOU Large General Service ("LGS") customer classes. Specifically, I addressed the economic impact of the demand ratchets in these classes on storage customers. This reply testimony addresses the direct testimony of Mr. Miessner filed on April 3, 2017 supporting demand ratchets in the LGS rate classes.

II. BACKGROUND

Q: WHAT DID YOU RECOMMEND WITH RESPECT TO THE COMPANY'S DEMAND RATCHETS IN THE LARGE GENERAL SERVICE ("LGS") CLASSES IN YOUR DIRECT TESTIMONY?

A: I recommended that the Commission create an alternative to APS's existing demand ratchet rates for LGS storage customers in order to promote the adoption of energy storage technologies. Since demand ratchets effectively eliminate storage as a viable option for large customers, I proposed that APS be directed to provide an optional non-ratchet LGS tariff that would allow customers seeking to install storage the opportunity to do so.

In my direct testimony, I explained that APS's existing, and proposed, rate design with demand ratchets does not send appropriate signals to incentivize the efficient use of the system. Instead, APS's demand ratchet structure operates essentially as a fixed charge because the customer must wait approximately 1 year to receive any economic benefit from reducing demand. Since the demand ratchet is based on a customer's maximum demand on essentially any day or hour in the months May through October, there is little incentive for a customer to reduce demand when it matters most to APS: during peak hours.

I further pointed out that a demand ratchet significantly reduces the economic incentive associated with adopting storage. For example, commercial customers with storage who reduce demand peaks to less than 80% of the customer's May-October summer peak will not realize savings for the following 12 months as a result of the ratchet. The risk of having a year's worth of potential savings eliminated by one adverse 15 minute interval is too high for potential storage customers and financiers to reasonably bear.

Similarly, once the ratchet is set, there is little to no motivation for a customer to reduce demand in lower-demand months. As a result, with a ratchet in place, storage technologies provide no demand charge reduction benefit to the customer in these lower demand months. Ideally, the demand charge for large customers with storage would send a signal for these customers to reduce demand in all months, even those months where the customer's monthly peak demand does not approach the customer's annual peak demand, thereby promoting the use of storage more evenly.

I also pointed out that APS's demand ratchets were inconsistent with the Commission's efforts to allow customers to control their utility bills while benefitting the entire system by increasing the adoption of energy storage. In the recent Tucson Electric Power ("TEP") rate case, RUCO witness Lon Huber testified that year-round demand ratchets like those proposed by TEP were a deterrent to the adoption of battery storage technology.[1] Specifically, Mr. Huber testified that, "in terms of like a 24-hour demand charge with a full like ratchet, I mean that would kill storage right out of the

[1] Transcript of Testimony from Phase I Hearing in Docket No. E-01933A-15-0322, Huber Vol. VII at 1575:12-20.

gate."[2] Killing storage or prohibiting commercial customers from having the option to manage their use through the addition of storage is obviously not an acceptable outcome. I also briefly discussed the recently litigated TEP case, Docket No. E-01933A-15-0239, where in response to intervenor concerns regarding the incompatibility of demand ratchets and storage, the Commission directed the utility to create a non-ratcheted time-differentiated *optional* rate for LGS customers seeking to adopt storage.

III. REBUTTAL TO APS DIRECT TESTIMONY

Q: WHAT DID THE COMPANY RECOMMEND WITH RESPECT TO DEMAND RATCHETS IN THE LARGE GENERAL SERVICE ("LGS") CLASSES IN ITS DIRECT TESTIMONY?

A: Company witness, Charles A. Miessner, recommended the continued use of demand ratchets in the LGS classes. In his direct testimony, Mr. Miessner's defends the use of ratchets in the LGS classes purely from a *cost recovery* perspective, not from a *price signal* perspective, which was EFCA's primary focus. In my opinion, good rate design will accomplish both goals. It will not only recover the costs of the system but it will also send the appropriate price signals to customers to use the system more efficiently.

For example, Mr. Miessner's testimony states that demand ratchets help to "recover the appropriate amount of grid costs from specific customers when their monthly load varies significantly."[3] This is "especially important when grid costs are

[2] Id.
[3] Miessner Direct Testimony at 18/19-20.

upgraded to serve a specific customer."[4] His testimony, and the examples in his testimony, focus on a 1,000 kW grid upgrade to serve one specific customer. His examples show how this customer, without demand ratchets, would not pay its cost of service for the grid upgrades and how these costs would be passed on to other customers in the Company's next rate case.[5] He testifies that, without demand ratchets, the demand charges would be higher in the class[6] and implies that other customers would not appreciate that result.[7] Additionally, by proposing that commercial customers be allowed a non-ratcheted LGS rate, Mr. Miessner concludes that EFCA is advocating for the elimination of ratchets altogether, which is not the case.

Q: ARE THERE PROBLEMS WITH MR. MIESSNER'S EXAMPLES?

A: Yes. Mr. Miessner's examples are based on several false premises:

1. that grid costs are upgraded to serve one specific customer;
2. that this specific customer actually pays for only those upgrade costs;
3. that EFCA is proposing to eliminate the demand ratchets for the class;
4. that other customers would object if the ratchets were eliminated; and,
5. that ratchets are necessary to fully recover the costs of the system.

Q: WHY IS IT INACCURATE TO ASSUME THAT THE SYSTEM IS UPGRADED TO SERVE ONE CUSTOMER?

A: The system is almost never upgraded to serve one customer, especially not for a 1MW

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[4] Id.
[5] Id. at 18/22-28. Also, Miessner Direct at 22/9-11.
[6] Miesnner Direct at 23/4-6.
[7] Miessner Direct at 22/21.

customer. It would be impractical to add 1,000 kW of generation capacity every time a new 1,000 kW customer comes on to the system. It would be equally impractical to add a 1,000 kW transmission line, or a 1,000 kW substation. Grid additions are never that precise. They tend to be much more *lumpy,* with excess capacity built into virtually every grid upgrade. Moreover, the cost of this excess capacity is paid by all customers in the class. In other words, grid upgrade costs, as well as the excess upgrade costs, are socialized among all customers in the class. It may be true that, if one customer reduces its load through energy efficiency, demand side management or storage, system costs associated with that load may be passed on to other customers, however, that is only true in the short run. In the long run, all customers benefit from these load reductions, because the next lumpy capacity upgrade will be much smaller and much less expensive, or the next upgrade will be pushed out much further into the future than it otherwise would have been without these reductions.

Q: ARE THERE TIMES WHEN GRID UPGRADES ARE MADE FOR ONE SPECIFIC CUSTOMER?

A: This almost never happens. There may be some instances where a substation is built for a large customer, or a transmission line is extended for a large customer, but in these situations, the customer will generally pay for the extension through a customer advance or a Contribution in Aid of Construction ("CIAC"). More importantly, production capacity is virtually never expanded for one customer. Thus, Mr. Miessner's examples, which serve as the rationale for all of his direct testimony, are based on a situation that rarely occurs with respect to transmission and distribution costs and virtually never occurs with respect to production costs.

Q: WHAT IS THE COMPANY'S LINE EXTENSION POLICY?

A: According to APS response to EFCA 32.1(b), the Company uses an economic feasibility study to determine the rate of return for a new project. If the rate of return is below the most recent authorized rate of return, or if the revenue stream from the project is uncertain based on bill projections, including all rate provisions and ratchets, APS will require an applicant to provide an advancement of funds up to the total cost of the facilities investment so that the APS share of the extension investment will not cause an undue burden on current APS customers. If actual revenues exceed estimates, the customer may be eligible for a refund. Any un-refunded advance amount after five years is forfeited and reclassified as CIAC.[8] As a result, Mr. Miessner's rationale is undermined to the extent customers pay for their own upgrades. A customer cannot shift costs to other customers if it has already paid for those costs in advance.

Q: WHY DO YOU SAY THAT IT IS INACCURATE FOR MR. MIESSNER TO SUGGEST THAT A CUSTOMER PAYS ONLY FOR ITS SPECIFIC GRID UPGRADE COSTS?

A: Mr. Miessner's examples all assume that the customer in his examples exclusively pays for its specific grid upgrade costs. If this were the case, the customer in his examples would pay lower costs year after year as the customer's specific investment levels decrease each year through depreciation recoveries. But, this is not how ratemaking works. Instead, system costs are socialized among all class members. So, instead of costs going down each year as the specific upgrade costs for a specific customer are recovered, costs remain the same, or usually increase, as new investments for other customers are added to the system, and the costs of these additions are spread among all customers in the class. Again, if a customer reduces load by adding storage, or through other energy efficiency or demand-side management measures, that customer's avoided costs may be socialized among the other class members in the short run, but in the long run, all customers in the class benefit from lower rates as new capacity investments are avoided.

Q; WHY IS IT INACCURATE TO SAY THAT EFCA IS RECOMMENDING THAT RATCHETS BE ELIMINATED FOR THE ENTIRE CLASS?

A: EFCA's recommendation is to provide an option to the demand ratchets for storage customers only. This approach avoids all of the problems outlined in Mr. Miessner's testimony. This approach allows the Company to maintain its cost-recovery certainty for the vast majority of the LGS class, while providing the opportunity to expand storage technology on the system. In the long run, this will save all customers money by leveling overall load which will help to avoid expensive future capacity additions.

Q: IS THERE A RISK THAT TOO MANY CUSTOMERS WILL MIGRATE TO THE NON-RATCHETED LGS RATES CAUSING AN UNDER-RECOVERY OF COSTS IN THE LGS CLASSES?

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[8] See Service Schedule 3.1.5.3.

A: No. There should be no meaningful risk of under-recovery from customer migration to the non-ratcheted LGS rates for two reasons. First, the optional non-ratcheted LGS rates will be open to storage customers only, which will significantly limit migration to those rates. Second, the non-ratcheted rates should be revenue neutral to APS. The demand charges will be higher without the ratchets, but the overall revenue collected under either rate schedule, with or without the ratchets, should be about the same to the Company, as shown in Section IV below.

Q: WHY DO YOU SAY THAT IT IS INACCURATE FOR APS TO SUGGEST THAT OTHER CUSTOMERS IN THE CLASS WOULD NOT WANT THE RATCHETS REMOVED?

A: In my experience, it is very unlikely that other customers in the class would object to the removal of the ratchets. Ratchets are blunt instruments whose main purpose is to assure cost recovery for the utility. Ratchets are not effective for sending price signals to customers, as they do not allow customers to correct their usage patterns for many months. For example, time-of-use or time-varying rates would be much more attractive options for customers since they allow customers to make more current, real time choices.

The reality is that ratchets are installed for the benefit of the utility, not the customers. The primary purpose of ratchets is to assure full cost recovery. But, ratchets also provide a distinctly anti-competitive pricing component which serves to reduce or eliminate competition on the system from distributed generation, Combined Heat and

Power ("CHP") facilities, and storage. Commissions should not allow utilities to utilize rate design mechanisms to reduce or eliminate competition from new technologies. This elimination of competition comes: (1) at the expense of the customers wanting to utilize these technologies, (2) at the expense of other customers on the system who will benefit from the lower prices these technologies help bring about, and (3) at the expense of the local economy that will lose the job growth these new technologies could help provide. Since the Commission serves as the surrogate for the competitive markets, it should encourage, not discourage, competition.

Q: DO OTHERS RECOGNIZE THAT RATCHETS CAN BE A DISADVANTAGE TO THE CUSTOMER LOOKING TO ADOPT ENERGY SAVING TECHNOLOGY?

A: Yes. In fact, APS's own expert witness, Ahmad Faruqui, gave a presentation on January 20, 2016 titled "A Conversation About Standby Rates" wherein he recognized that demand ratchets can be overly punitive on customers. Dr. Faruqui stated, "[u]nder this type of rate, it is possible that a customer will have a very rare outage event during a window when demand is measured. The unlucky customer will then be locked in at that rate for a long period even though their demand at that time was not representative of their expected capacity needs or the true costs they impose on the grid."[9]

Q: IS THAT ALL DR. FARUQUI SAID ABOUT DEMAND CHARGES?

[9] *See*, http://www.brattle.com/system/publications/pdfs/000/005/253/original/Michigan_Standby_Rates_(01-19-2016).pdf?1453481497 at slide 27, attached as Exhibit A.

No. In that same presentation, Dr. Faruqui admits that ratcheted demand charges "act as a disincentive for customers to self-generate."[10] I agree with Dr. Faruqui that these ratcheted demand charges clearly punish and provide a disincentive for the adoption of technology that enables a customer to lower their usage of grid supplied energy.

Q: DO YOU HAVE ANY OTHER EXAMPLES OF PEOPLE SHARING YOUR OPINION THAT RATCHETS FAVOR THE UTILITY WHILE DISCOURAGING CUSTOMERS FROM ADOPTING ENERGY SAVING MEASURES?

Yes, the Regulatory Assistance Project authored a paper that includes, among other conclusions, that demand ratchets, "provide stable revenues to utilities, but discourage energy efficiency throughout the year, since a significant part of the cost of service is fixed and the savings from peak load reduction from energy efficiency are not realized until the ratchet period has been completed."[11] RAP continues and says that "Demand ratchets fail to capture the effects of time diversity and non-coincidence of a customer's peak demand with the peak usage of any portion of the system."[12]

Q: WHY IS IT INACCURATE FOR THE COMPANY TO SUGGEST THAT RATCHETS ARE NECESSARY TO FULLY RECOVER COSTS IN THE LGS CLASSES?

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[10] *See Id*. at slide 12.

[11] *See* Lazar, J. and Gonzalez, W. (2015). Smart Rate Design for a Smart Future. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7680 at p. 38 attached hereto as Exhibit B.

A: In response to EFCA 32.4, APS admits that ratchets were installed in the LGS rate classes on July 1, 2012. This means that, before 2012, the costs of the LGS rate classes were recovered without the use of ratchets. This fact further supports my main concern that the real purpose of ratchets is to thwart competition from distributed generation, CHP and storage, all at the expense of customers and the economy.

[12] *See Id*. at page 84

IV. OPTIONAL LGS STORAGE RATES

Q: PLEASE DESCRIBE THE OPTIONAL LGS STORAGE RATES YOU ARE PROPOSING.

A: The Company contends that "if the ratchet were eliminated, the demand rates for E-32 L would have to be increased to make up for the resulting revenue shortfall."[13] In response to data request EFCA 31.5, the Company stated that the estimated increase to demand charges "would be roughly 5% on average." Therefore, based upon this 5% estimated average increase, I have calculated optional proposed LGS Storage Rates without ratchets and without declining block tiers, as shown in Table 1 below:

Table 1: Optional LGS Storage Rates

Source: EFCA 29.1 and EFCA 31.5(c)	**Rate Class: E-32-L** APS Proposed Settlement kW Rates (with Ratchet)	APS Units	APS Proposed Revenue Settlement	**Step 1 - Remove Ratchets** EFCA Proposed No Ratchet	EFCA Units	EFCA Proposed Revenue	**Step 2 - Remove Tiers** Avg Rev	Avg Units	EFCA Proposed Rates
Summer Days									
kW Secondary tier 1	$ 25.37	437,397	$11,097,637	$ 26.71	415,527	$11,097,637	$ 58,489,047	2,972,860	$ 19.67
kW Secondary tier 2	17.61	2,691,929	47,391,410	18.53	2,557,333	47,391,410			
kW Primary tier 1	23.05	34,800	802,105	24.26	33,060	802,105	8,030,347	451,488	$ 17.79
kW Primary tier 2	16.41	440,451	7,228,241	17.27	418,428	7,228,241			
kW Transmission tier 1	17.62	2,600	45,822	18.55	2,470	45,822	364,199	28,205	$ 12.91
kW Transmission tier 2	11.75	27,089	318,377	12.37	25,735	318,377			
Proof Summer Demand Revenue			$66,883,593			$66,883,593	$ 66,883,593		
Winter Days									
kW Secondary tier 1	$ 25.37	441,333	$11,197,501	$ 26.71	419,266	$11,197,501	$ 54,325,948	2,746,561	$ 19.78
kW Secondary tier 2	17.61	2,449,784	43,128,447	18.53	2,327,295	43,128,447			
kW Primary tier 1	23.05	35,600	820,544	24.26	33,820	820,544	$ 7,614,387	427,102	$ 17.83
kW Primary tier 2	16.41	413,981	6,793,842	17.27	393,282	6,793,842			
kW Transmission tier 1	17.62	2,400	42,298	18.55	2,280	42,298	$ 343,433	26,621	$ 12.90
kW Transmission tier 2	11.75	25,622	301,135	12.37	24,341	301,135			
Proof Winter Demand Revenue			$62,283,768			$62,283,768	$ 62,283,768		

[13] Direct Testimony of Charles Miessner, p. 23, lines 4-5.

Q: DO YOU ALSO PROPOSE OPTIONAL LGS-TOU STORAGE RATES?

A: Yes. The Company provides an LGS-TOU tariff, E-32-TOU-L. I propose an optional TOU storage tariff that eliminates the ratchets and tiers, as was done for the LGS standard tariff alternative above. In addition, the APS E-32-TOU-L tariff includes a non-traditional off-peak demand charge that is rarely seen. For the optional TOU storage rate, the Commission should eliminate the off-peak demand charge in the E-32TOU-L rate, and place the associated revenues in the on-peak demand charge to create a stronger price signal to incentivize peak demand reduction, as shown in Table 2 below:

Table 2: Optional LGS-TOU Storage Rates

	Rate Class E-32-TOU-L			Step 1 - Remove Ratchets			Step 2 - Remove Tiers and Off Peak kW		
Source: EFCA 29.1 and EFCA 31.5(c)	APS Proposed Settlement kW Rates (with Ratchet	APS Units	APS Proposed Revenue	EFCA Proposed (No Ratchet)	EFCA Units	EFCA Proposed Revenue kW Rates (No Ratchet)	Avg Rev	Avg Units	EFCA Proposed Rates
Summer Days									
kW tier 1 - secondary - on	$ 17.51	27,250	$ 477,093	$ 18.43	25,888	$ 477,093	$ 3,678,113	216,890	$ 16.96
kW tier 2 - secondary - on	11.80	201,055	2,371,444	12.42	191,002	2,371,444			
kW tier 1 - secondary - off	6.40	27,223	174,118	6.73	25,862	174,118			
kW tier 2 - secondary - off	3.37	194,498	655,458	3.55	184,773	655,458			
kW tier 1 - primary - on	16.94	5,700	96,535	17.83	5,415	96,535	$ 1,257,187	75,627	$ 16.62
kW tier 2 - primary - on	11.71	73,907	865,451	12.33	70,212	865,451			
kW tier 1 - primary - off	5.68	6,115	34,727	5.98	5,809	34,727			
kW tier 2 - primary - off	3.27	79,607	260,474	3.44	75,627	260,474			
kW tier 1 - transmission - on	15.92	573	9,120	16.75	544	9,120	$ 149,693	10,075	$ 14.86
kW tier 2 - transmission - on	10.48	10,032	105,115	11.03	9,530	105,115			
kW tier 1 - transmission - off	4.87	559	2,723	5.13	531	2,723			
kW tier 2 - transmission - off	3.14	10,435	32,735	3.30	9,913	32,735			
Proof Summer Demand Revenue			$ 5,084,993			$ 5,084,993	$5,084,993		
Winter Days									
kW tier 1 - secondary - on	$ 17.51	36,700	$ 642,544	$ 18.43	34,865	$ 642,544	$ 3,681,359	217,795	$ 16.90
kW tier 2 - secondary - on	11.80	192,558	2,271,222	12.42	182,930	2,271,222			
kW tier 1 - secondary - off	6.40	26,700	170,773	6.73	25,365	170,773			
kW tier 2 - secondary - off	3.37	177,098	596,820	3.55	168,243	596,820			
kW tier 1 - primary - on	16.94	5,280	89,422	17.83	5,016	89,422	$ 905,811	54,593	$ 16.59
kW tier 2 - primary - on	11.71	52,186	611,098	12.33	49,577	611,098			
kW tier 1 - primary - off	5.68	5,376	30,530	5.98	5,107	30,530			
kW tier 2 - primary - off	3.27	53,411	174,761	3.44	50,740	174,761			
kW tier 1 - transmission - on	15.92	576	9,168	16.75	547	9,168	$ 171,302	11,747	$ 14.58
kW tier 2 - transmission - on	10.48	11,789	123,525	11.03	11,200	123,525			
kW tier 1 - transmission - off	4.87	576	2,806	5.13	547	2,806			
kW tier 2 - transmission - off	3.04	11,789	35,803	3.20	11,200	35,803			
Proof Winter Demand Revenue			$ 4,758,472			$ 4,758,472	$4,758,472		

Q: HAS ANYTHING OF NOTE BEEN FILED SINCE YOUR OPENING TESTIMONY ON THE SETTLEMENT AGREEMENT?

A: Yes, APS filed its 2017 Integrated Resource Plan ("IRP").

Q: WHAT DOES THE IRP SAY ABOUT WHY ENERGY STORAGE IS GOOD FOR THE SYSTEM?

APS acknowledges that energy storage "could displace other resource additions and expand the Company's options in flexible capacity at an affordable price."[14] In addition, the IRP describes how paring storage with distributed generation increases the value of distributed generation resources and solves for any misalignment that may occur between the time of solar generation and the system peak.[15] This is further acknowledgement of the value of energy storage that the Commission has seemingly already recognized in making a significant push to encourage this promising technology.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

[14] *See* APS 2017 Integrated Resource Plan: http://docket.images.azcc.gov/0000178832.pdf at p. 21.
[15] *See Id.* at p. 58.

EXHIBIT A

Demand charge ratchets are a controversial feature in some standby rates

Some demand charges are based on a single measure of a customer's kW-demand during a particular time period

- This demand charge "ratchet" may then apply to a customer for several months or even a year
- Under this type of rate, it is possible that a customer will have a very rare outage event during a window when demand is measured
- The unlucky customer will then be locked in at that rate for a long period even though their demand at that time was not representative of their expected capacity needs or the true costs they impose on the grid

EXHIBIT B

revenue responsibility than would occur if demand charges were based on usage during the system coincident peak.

A demand "ratchet" is a rate element that requires a customer to pay a demand charge in every month that is based on their highest usage during the year, often based on summer peak demand. These provide stable revenues to utilities, but discourage energy efficiency throughout the year, since a significant part of the cost of service is fixed and the savings from peak load reduction from energy efficiency are not realized until the ratchet period has been completed. This also has the effect of aggravating the mismatch between on-peak costs and on-peak usage, noted above.

Power Supply Costs

Power supply costs include the investment-related capital costs of power plants and transmission costs, fuel and purchased power costs, and generation and transmission operations and maintenance (O&M). In the past, many of these, such as capital costs and purchased power demand charges, were treated as demand-related costs, allocated to each customer class on a measure of demand (typically class contribution to system coincident peak, average demand, or a combination of the two). These may be reflected in individual customer demand charges, based on individual customer peak usage (not necessarily coincident to the system peak) for large-use (i.e., commercial and industrial) customers, or, preferably, in time-of-use (TOU) energy charges.

Fuel and purchased power costs, most of which were treated as energy-related costs, are typically allocated among the classes on a measure of total energy consumed (annual, seasonal, or time-varying). For electric utilities, as in other industries, capital costs, on the one hand, and short-run incremental unit costs (e.g., fuel and purchased power costs), on the other, are substitutes. A capital-intensive generating resource like wind, solar, or nuclear displaces fuel costs, typically gas or coal; a local resource like a combustion turbine displaces the need for transmission.

Likewise, a market mechanism that pays customers to reduce demand during high price periods or when the system is under stress displaces the need for generation, transmission, and distribution to meet short-term peaking requirements. In restructured and competitive wholesale power markets, however, the power supply costs discussed above in this section are nearly all recovered on a time-varying energy basis. A small portion may be recovered in capacity payments, but experience in the PJM and ISO-NE regions shows that, where allowed to compete, demand response potential quickly bids down the prices for short-duration capacity.

Principles for Rate Design in the Wake of Change

Good rate design should work in concert with the industry's clean technological innovations and institutional changes. Accomplishing this requires the application of well-established principles to inform the design of rates that promote economic efficiency, equity, and utility revenue recovery. This will be critical in a future characterized by significant customer-side resource investment and smart technology deployment. The advantages of a state that embraces these efficiency, equity, and utility revenue adequacy goals are significant, especially in maintaining a state's competitiveness and promoting customer choice and ingenuity. Unleashing the potential of new technologies will also require consideration of changing stakeholder interests as the power sector evolves.

Best practice rate design solutions should balance the goals of:

- Assuring recovery of prudently incurred utility costs;
- Maintaining grid reliability;
- Assuring fairness to all customer classes and sub-classes;
- Assisting the transition of the industry to a clean energy future;
- Setting economically efficient prices that are forward-looking and lead to the optimum allocation of utility and customer resources;
- Maximizing the value and effectiveness of new technologies as they become available and are deployed on, or alongside, the electric system; and
- Preventing anti-competitive or anti-innovation market structures or behavior.

Stakeholder Interests

Finding common ground on rate design among utilities, consumer advocates, environmental advocates, and others is not easy. The interests are different, the perspectives are different, and even the perceived public policy goals are viewed differently by different parties.

Utility Interests

Utilities tend to see costs associated with generating plant, transmission, distribution, and customer billing as "fixed